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UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

Before the Atomic Safety and Licensing Board

In the Matter of CLEVELAND ELECTRIC ILLUMINATING COMPANY, Et Al. (Perry Nuclear Power Plant, Units 1 and 2)	Docket Nos. 50-440 50-441 (Operating License)

OHIO CITIZENS FOR RESPONSIBLE ENERGY MOTION FOR LEAVE TO FILE ITS CONTENTIONS 21 THROUGH 26

Ohio Citizens for Responsible Energy ("OCRE") hereby moves the Licensing Board to grant OCRE leave to supplement further its Petition to Intervene by filing its Contentions 21 through 26 in the above-captioned proceeding. OCRE will first provide general explanations of each contention and then will address the filing requirements of 10 CFR 2.714.

Contention 21 Turbine Missiles

OCRE contends that the placement and orientation of the PNPP turbine-generators are unacceptable because low trajectory turbine missiles could strike safety-related targets, thereby endangering the safe operation of the facility. This concern was identified as an open item in Section 3.5.1.3 of the Perry SER, NUREG-0887. The ACRS has also expressed dissatisfaction with the progress being made on the resolution of this issue (ACRS Report on the Perry Nuclear Power Plant, Unit 1, dated July 13, 1982).

The Applicants' FSAR, in its treatment of this issue, refers to a report prepared by their A/E, Gilbert Associates

DS03

Inc., entitled "An Analysis of Low Trajectory Turbine Missile Hazards, Perry Nuclear Power Plant, Units 1 and 2," GAI Report No. 1848, October 1976. This report indeed indicates that the following structures are within the low trajectory missile strike zone: control room; cable spreading room; HVAC equipment room; intermediate building; auxiliary building; electrical penetration area; reactor buildings of both Units 1 and 2. The estimated damage to these structures resulting from turbine missile impact includes rendering the control room inoperable, the collapse of buildings on safety-related electrical cables and equipment, and penetration of the containment.

Obviously these consequences are unacceptable. This situation must be corrected before Perry can be allowed to operate.

<u>Contention 22</u> New Mark III Containment Concerns

Recently J.M. Humphrey, a former employee of General Electric, identified a number of concerns pertaining to the Mark III containment, such as is employed at PNPP. Mr. Humphrey, who was for 3 years GE's Lead Systems Engineer for Containment, and who was involved in the STRIDE program, approached Mississippi Power & Light, applicant for Grand Gulf, with a list of 22 major issues, some of which have been further divided into sub-issues (66 total). Although some of these issues did not apply to Grand Gulf, most are still unresolved, and remain so for Perry as well (<u>see</u> July 14, 1982 letter to D. Davidson, CEI from A. Schwencer, NRC requesting additional information on these concerns). OCRE therefore adopts as sub-parts to this contention the 66 concerns identified by Mr. Humphrey (and listed in

Attachment 1).

<u>Contention 23</u> Seismic Evaluation of BWR Core Thermal-Hydraulics

OCRE contends that the Applicants' seismic analysis (and the NRC Staff's review of same in the SER) is deficient because this analysis totally neglects the response of the core thermal-hydraulic design to a seismic event. Because the BWR uses a two-phase moderator/coolant, it is inherently susceptible to power excursion transients resulting from events affecting void distribution. An earthquake could cause sloshing of the water in the reactor vessel, thus resulting in void collapse and/or redistribution. <u>See</u> Dr. Richard E. Webb, <u>The Accident Hazards of Nuclear Power Plants</u> (University of Mass., 1976) at 28.

The seismic analyses performed for PNPP deal only with the response of components and structures and ignore the core thermal-hydraulic response. This analysis must be performed before Perry is allowed to operate. In light of the recommendation of the ACRS that studies be conducted to evaluate margins available following an earthquake of greater severity than the safe shutdown earthquake (SSE), OCRE suggests that this analysis be based on an earthquake of greater severity than the SSE.

<u>Contention 24</u> In-Core Thermocouples

Applicants should conform to the requirements of Regulatory Guide 1.97, Revision 2, and TMI Action Plan item II.F.2 by installing in-core thermocouples at Perry. In-core thermocouples provide an indication of inadequate core cooling (ICC) and are a redundant and diverse means by which to detect reactor coolant level. As discussed in Section 4.4.7 of the SER, the Staff, which previously required in-core thermocouples in BWRs, has now agreed with General Electric and the BWR Owners Group that the issue should be broadened from the specific requirement for in-core thermocouples to that of monitoring inadequate core cooling. OCRE contends that in-core thermocouples should be used at Perry.

GE and the BWR Owners Group argued against the use of in-core thermocouples, citing excessive costs and claiming that the thermocouples offer no advantage in monitoring ICC or reactor water level. The latter claim is based upon heat transfer calculations which indicate an excessive time constant in thermocouple response; the Owners Group believes that this could provide ambiguous information to plant operators (see "Thermal Analysis of In-Core Thermocouples in BWRs," prepared by S. Levy, Inc., November 1981). However, an analysis performed by Battelle Laboratories indicates that the time lag might only be 1-1½ minutes (letter from C.L. Wheeler, Battelle, to W.V. Johnston, NRC, dated April 6, 1981). GE does admit that thermocouples could be useful in one situation: loss of coolant inventory with no water makeup systems available (General Electric Evaluation of the Need for BWR Core Thermocouples, November 1981).

OCRE contends that these analyses ignore another condition in which in-core thermocouples can provide vital information: a fuel bundle blockage accident. GE, in its evaluation of this accident (Appendix B of the report mentioned above), makes several key assumptions as to the course of this accident so as to support its conclusion that thermocouples are of no value.

That these assumptions are arbitrary and unproven is discussed in The Accident Hazards of Nuclear Power Plants, by Dr. Richard E. Webb, at 59-61. OCRE suggests that signals from thermocouples located near the fuel bundle experiencing blockage would alert operators that this situation was occurring so that they could scram the reactor. This action would limit the severity of the overheating of the fuel bundle and avoid the possibility of propagating core damage. Relying on other measured variables, such as fission product activity and hydrogen concentration, to indicate this condition, as GE suggests, requires that fuel damage must have already occurred before any corrective action can be taken. OCRE maintains that this is unacceptable, as this type of accident can lead to a cascading core meltdown.

Contention 25 Steam Erosion

OCRE contends that Applicants are not prepared to prevent, discover, assess, and mitigate the effects of steam erosion on components of PNPP which will be subjected to steam flow. Steam erosion has been identified as the cause of recent failures of valves and piping (MSIVs and turbine exhaust lines: see NRC Information Notices 82-22 and 82-23). The NRC Staff has identified Applicants' lack of an inservice testing program for pumps and valves and leak testing of valves as an open item in Section 3.9.6 in the SER.

<u>Contention 26</u> Control Room Fire Suppression

Applicants are proposing a carbon dioxide fire suppression system for use in the control room. The Staff has identified this as an open item in Section 9.5.1.6.2 of the SER for the following reasons: (1) CO_2 has not been tested and approved as a suppression agent for use in the GE Power Generation Control Complex (PGCC) design implemented at Perry; (2) CO_2 may leak from the underfloor into the control room, possibly causing injury to operators or forcing evacuation of the control room. The Staff instead advocates using Halon 1301.

OCRE contends that all advantages and disadvantages of each suppressent should be thoroughly evaluated before choosing a particular system, especially in regard to toxicity. For instance, NFPA 12, Article 121 lists reduced visibility and possible oxygen deficiency as hazards resulting from the discharge of large amounts of CO_2. However, according to NFPA 12, Articles A-1200 to A-1202, the hazards resulting from the use of Halon 1301 are twofold: those due to the natural agent, bromotrifluoromethane ($CBrF_3$), and those due to its decomposition products.

The effects of $CBrF_3$ itself include dizziness, impaired coordination, and reduced mental acuity. It is recommended that personnel do not remain in an area where Halon 1301 concentrations exceed 7% and that they remain no more than a few minutes in an area with Halon concentrations less than 7%. Persons can be quickly incapacitated by higher levels (10-15%).

Halon decomposition products include halogen acids, free halogens, and carbonyl halides. These substances are both hazardous to personnel and corrosive to equipment. In addition, free halogens can poison charcoal filters in the control room HVAC system. These decomposition products cannot be avoided in the presence of flame, since the mechanism by which Halon inhibits combustion involves its decomposition.

Furthermore, halons are known to cause degradation of the stratospheric ozone layer.

OCRE believes that the Staff has neglected many toxicological and environmental factors in its evaluation of this issue.

Filing Requirements under 10 CFR 2.714

OCRE has met the requirements for late filing listed in 10 CFR 2.714(a)(1). All of the contentions filed herein are based upon the Perry SER, NUREG-0887. The SER constituted OCRE's first notice of the concerns identified in Contentions 21, 22, and 26. Contention 23 is based on the deficiency of the Staff's analysis in the SER. Similarly, Contention 24 was filed at this time because prior to the issuance of the SER, OCRE assumed that in-core thermocouples would be required at Perry. The Staff required them at Grand Gulf (Grand Gulf SER, NUREG-0831 at 22-22). Contention 25, in addition to referring to the Staff's finding as stated in the SER, is based upon two recently issued NRC Information Notices. Thus there exists good cause for this late filing.

OCRE has only this forum in which to protect its interests; in addition, no other parties to this proceeding have raised these issues. That OCRE's participation will aid in the development of a sound record has been affirmed by the Licensing Board (Memorandum and Order of July 12, 1982, LBP-82-53, at 5). While the admission of these contentions might cause delay, this should not be of concern to any party, since Applicants recently requested that the completion dates for Units 1 and 2 of Perry be extended to 1985 and 1991, respectively (<u>see</u> Attachment 2). These factors thus favor the admission of these contentions into this proceeding.

Respectfully submitted,

Susan L. Hiatt

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ATTACHMENT 1

HUMPHREY CONTAINMENT CONCERNS

1. Effects of Local Encroachments on Pool Swell Loads

1.1 Presence of local encroachments such as the TIP platform, the drywell personnel airlock and the equipment and floor drain sumps may increase the pool swell velocity by as much as 20 per cent.

1.2 Local encroachments in the pool may cause the bubble breakthrough height to be higher than expected.

1.3 Additional submerged structure loads may be applied to submerged structures near local encroachments.

1.4 Piping impact loads may be revised as a result of the higher pool swell velocity.

1.5 Impact loads on the HCU floor may be imparted and the HCU modules may fail which could prevent successful scram if the bubble breakthrough height is raised appreciably by local encroachments.

1.6 Local encroachments or the steam tunnel may cause the pool swell and froth to move horizontally and apply lateral loads to the gratings around the HCU floor.

1.7 GE suggests that at least 1500 square feet of open area should be maintained in the HCU floor. In order to avoid excessive pressure differentials, at least 1500 ft.^{2} of opening should be maintained at each containment elevation.

2. Safety Relief Valve Discharge Line Sleeves

2.1 The annular regions between the safety relief valve lines and the drywell wall penetration sleeves may produce condensation oscillation (c.o.) frequencies near the drywell and containment wall structural resonance frequencies.

2.2 The potential condensation oscillation and chugging loads produced through the annular area between the SRVDL and sleeve may apply unaccounted for loads to the SRVDL. Since the SRVDL is unsupported from the quencher to the inside of the drywell wall, this may result in failure of the line.

2.3 The potential condensation oscillation and chugging loads produced through the annular area between the SRVDL and sleeve may apply unaccounted for loads to the penetration sleeve. The loads may also be at or near the natural frequency of the sleeve.

3. ECCS Relief Valve Discharge Lines Below the Suppression Pool Level

3.1 The design of the STRIDE plant did not consider vent clearing, condensation oscillation and chugging loads which might be produced by the actuation of these relief valves.

3.2 The STRIDE design provided only nine inches of submergence above the RHR relief valve discharge lines at low suppression pool levels.

3.3. Discharge from the RHR relief valves may produce bubble discharge or other submerged structure loads on equipment in the suppression pool.

3.4 The RHR heat exchanger relief valve discharge lines are provided with vacuum breakers to prevent negative pressure in the lines when discharging steam is condensed in the pool. If the valves experience repeated actuation, the vacuum breaker sizing may not be adequate to prevent drawing slugs of water back through the discharge piping. These slugs of water may apply impact loads to the relief valve or be discharged back into the pool at the next relief valve actuation and apply impact loads to submerged structures.

3.5 The RHR relief valves must be capable of correctly functioning following an upper pool dump which may increase the suppression pool level as much as five feet creating higher back pressures on the relief valves.

3.6 If the RHR heat exchanger relief valves discharge steam to the upper levels of the suppression pool following a design basis accident, they will significantly aggravate suppression pool temperature stratification.

3.7 The concerns related to the RHR heat exchanger relief valve discharge lines should also be addressed for all other relief lines that exhaust into pool. (p. 132 of 5/27/82 transcript)

4. Suppression Pool Temperature Stratification

4.1 The present containment response analyses for drywell break accidents assume that the ECCS systems transfer a significant quantity of water from the suppression pool to the lower regions of the drywell through the break. This results in a pool in the drywell which is essentially isolated from the suppression pool at a temperature of approximately 135°F. The containment response analysis assumes that the drywell pool is thoroughly mixed with the suppression pool. If the inventory in the drywell is assumed to be isolated and the remainder of the heat is discharged to the suppression pool, an increase in bulk pool temperature of 10°F may occur.

4.2 The existence of the drywell pool is predicated upon continuous operation of the ECCS. The current emergency procedure guidelines require the operators to throttle ECCS operation to maintain vessel level below level 8. Consequently, the drywell pool may never be formed.

4.3 All Mark III analyses presently assume a perfectly mixed uniform suppression pool. These analyses assume that the temperature of the suction to the RHR heat exchangers is the same as the bulk pool temperature. In actuality, the temperature in the lower part of the pool where the suction is located will be as much as 7½°F cooler than the bulk pool temperature. Thus, the heat transfer through the RHR heat exchanger will be less than expected.

4.4 The long term analysis of containment pressure/temperature response assumes that the wetwell airspace is in thermal equilibrium with the suppression pool water at all times. The calculated bulk pool temperature is used to determine the airspace temperature. If pool thermal stratification were considered, the surface temperature, which is in direct contact with the airspace, would be higher. Therefore the airspace temperature (and pressure) would be higher.

4.5 A number of factors may aggravate suppression pool thermal stratification. The chugging produced through the first row of horizontal vents will not produce any mixing from the suppression pool layers below the vent row. An upper pool dump may contribute to additional suppression pool temperature stratification. The large volume of water from the upper pool further submerges RHR heat exchanger effluent discharge which will decrease mixing of the hotter, upper regions of the pool. Finally, operation of the containment spray eliminates the heat exchanger effluent discharge jet which contributes to mixing.

4.6 The initial suppression pool temperature is assumed to be 95°F while the maximum expected service water temperature is 90°F for all GGNS accident analyses as noted in FSAR table 6.2-50. If the service water temperature is consistently higher than expected, as occurred at Kuosheng, the RHR system may be required to operate nearly continuously in order to maintain suppression pool temperature at or below the maximum permissible value.

4.7 All analyses completed for the Mark III are generic in nature and do not consider plant specific interactions of the RHR suppression pool suction and discharge.

4.8 Operation of the RHR system in the containment spray mode will decrease the heat transfer coefficient through the RHR heat exchangers due to decreased system flow. The FSAR analysis assumes a constant heat transfer rate from the suppression pool even with operation of the containment spray.

4.9 The effect on the long term containment response and the operability of the spray system due to cycling the containment sprays on and off to maximize pool cooling needs to be addressed. Also provide and justify the criteria used by the operator for switching from the containment spray mode to pool cooling mode, and back again. (pp. 147-148 of 5/27/82 transcript)

4.10 Justify that the current arrangement of the discharge and suction points of the pool cooling system maximizes pool mixing. (pp. 150-155 of 5/27/82 transcript)

5. Drywell to Containment Bypass Leakage

5.1 The worst case of drywell to containment bypass leakage has been established as a small break accident. An intermediate break accident will actually produce the most significant drywell to containment leakage prior to initiation of containment sprays.

5.2 Under Technical Specification limits, bypass leakage corresponding to $A/\sqrt{K} = 0.1$ ft.^{2} constitute acceptable operating conditions. Smaller-than-IBA-sized breaks can maintain break flow into the drywell for long time periods, however, because the RPV would be depressurized over a 6 hour period. Given, for example, an SBA with $A/\sqrt{K} = 0.1$, projected time period for containment pressure to reach 15 psig is 2 hours. In the latter 4 hours of the depressurization the containment would presumably experience ever-increasing overpressurization.

5.3 Leakage from the drywell to containment will increase the temperature and pressure in the containment. The operators will have to use the containments spray in order to maintain containment temperature and pressure control. Given the decreased effectiveness of the RHR system in accomplishing this objective in the containment spray mode, the bypass leakage may increase the cyclical duty of the containment sprays.

5.4 Direct leakage from the drywell to the containment may dissipate hydrogen outside the region where the hydrogen recombiners take suction. The anticipated leakage exceeds the capacity of the drywell purge compressors. This could lead to pocketing of hydrogen which exceeds the concentration limit of 4% by volume.

5.5 Equipment may be exposed to local conditions which exceed the environmental qualification envelope as a result of direct drywell to containment bypass leakage.

5.6 The test pressure of 3 psig specified for the periodic operational drywell leakage rate tests does not reflect additional pressurization in the drywell which will result from upper pool dump. This pressure also does not reflect additional drywell pressurization resulting from throttling of the ECCS to maintain vessel level which is required by the current EPGs.

5.7 After upper pool dump, the level of the pool will be 6 feet higher, and drywell-to-containment differential pressure will be greater than 3 psi. The drywell H_2 purge compressor head is nominally 6 psid. The concern is that after an upper pool dump, the purge compressor head may not be sufficient to depress the weir annulus enough to clear the upper vents. In such a case, H_2 mixing would not be achieved.

5.8 The possibility of high temperatures in the drywell without reaching the 2 psig high pressure scram level because of bypass leakage through the drywell wall should be addressed. (pp. 168-174 of 5/27/82 transcript)

6. RHR Permissive on Containment Spray

6.1 General Electric had recommended that the drywell purge compressors and the hydrogen recombiners be activated if the reactor vessel water level drops to within one foot of the top of active fuel. This requirement was not incorporated in the emergency procedure guidelines.

6.2 General Electric has recommended that an interlock be provided to require containment spray prior to starting the recombiners because of the large quantities of heat input to the containment. Incorrect implementation of this interlock could result in inability to operate the recombiners without containment spray.

6.3 The recombiners may produce "hot spots" near the recombiner exhausts which might exceed the environmental qualification envelope or the containment design temperature.

6.4 For the containment air monitoring system furnished by General Electric, the analyzers are not capable of measuring hydrogen concentration at volumetric steam concentrations above 60%. Effective measurement is precluded by condensation of steam in the equipment.

6.5 Discuss the possibility of local temperatures due to recombiner operation being higher than the temperature qualification profiles for equipment in the region around and above the recombiners. State what instructions, if any, are available to the operator to actuate containment sprays to keep this temperature below design values. (pp. 183-185 of 5/27/82 transcript)

7. Containment Pressure Response

7.1 The containment is assumed to be in thermal equilibrium with a perfectly mixed, uniform temperature suppression pool. As noted under topic 4, the surface temperature of the pool will be higher than the bulk pool temperature. This may produce higher than expected containment temperatures and pressures.

7.2 The computer code used by General Electric to calculate environmental qualification parameters considers heat transfer from the suppression pool surface to the containment atmosphere. This is not in accordance with the existing licensing basis for Mark III environmental qualification. Additionally, the bulk suppression pool temperature was used in the analysis instead of the suppression pool surface temperature.

7.3 The analysis assumes that the containment airspace is in thermal equilibrium with the suppression pool. In the short term this is non-conservative for Mark III due to adiabatic compression effects and finite time required for heat and mass to be transferred between the pool and containment volumes.

8. Containment Air Mass Effects

8.1 This issue is based on consideration that some Tech Specs allow operation at parameter values that differ from the values used in assumptions for FSAR transient analyses. Normally analyses are done assuming a nominal containment pressure equal to ambient (0 psig) a temperature near maximum operating (90°F) and do not limit the drywell pressure equal to the containment pressure. The Tech Specs operation under conditions such as a positive containment pressure (1.5 psig), temperatures less than maximum (60 or 70°F) and drywell pressure can be negative with respect to the containment (-0.5 psid). All of these differences would result in transient response different than the FSAR descriptions.

8.2 The draft GGNS technical specifications permit operation of the plant with containment pressure ranging between 0 and -2 psig. Initiation of containment spray at a pressure of -2 psig may reduce the containment pressure by an additional 2 psig which could lead to buckling and failures in the containment liner plate.

8.3 If the containment is maintained at -2 psig, the top row of vents could admit blowdown to the suppression pool during an SBA without a LOCA signal being developed.

8.4 Describe all of the possible methods both before and after an accident of creating a condition of low air mass inside the containment. Discuss the effects on the containment design external pressure of actuating the containment sprays. (pp. 190-195 of 5/27/82 transcript)

9. <u>Final Drywell Air Mass</u>

9.1 The current FSAR analysis is based upon continuous injection of relatively cool ECCS water into the drywell through a broken pipe following a design basis accident. The EPG's direct the operator to throttle ECCS operation to maintain reactor vessel level at about level 8. Thus, instead of releasing relatively cool ECCS water, the break will be releasing saturated steam which might produce higher containment pressurizations than currently anticipated. Therefore, the drywell air which would have been drawn back into the drywell will remain in the containment and higher pressures will result in both the containment and the drywell.

9.2 The continuous steaming produced by throttling the ECCS flow will cause increased direct leakage from the drywell to the containment. This could result in increased containment pressures.

9.3 It appears that some confusion exists as to whether SBA's and stuck open SRV accidents are treated as transients or design basis accidents. Clarify how they are treated and indicate whether the initial conditions were set at nominal or licensing values. (pp. 202-205 of 5/27/82 transcript)

10. <u>Drywell Flooding Caused by Upper Pool Dump</u>

10.1 The suppression pool may overflow from the weir wall when the upper pool is dumped into the suppression pool. Alternately, negative pressure between the drywell and the containment which occurs as a result of normal operation or sudden containment pressurization could produce similar overflow. Any cold water spilling into the drywell and striking hot equipment may produce thermal failures.

10.2 Describe the interface requirement (A-42) that specifies that no flooding of the drywell shall occur. Describe your intended methods to follow this interface or justify ignoring this requirement. (pp. 209-226 of 5/27/82 transcript)

11. Operational Control of Drywell to Containment Differential Pressures

Mark III load definitions are based upon the levels in the suppression pool and the drywell weir annulus being the same. The GGNS technical specifications permit elevation differences between these pools. This may effect load definition for vent clearing.

12. Suppression Pool Makeup LOCA Seal In

The upper pool dumps into the suppression pool automatically following a LOCA signal with a thirty minute delay timer. If the signal which starts the timer disappears on the solid state logic plants, the timer resets to zero preventing upper pool-dump.

13. Ninety Second Spray Delay

The "B" loop of the containment sprays includes a 90 second timer to prevent simultaneous initiation of the redundant containment sprays. Because of instrument drift in the sensing instrumentation and the timers, GE estimates that there is a 1 in 8 chance that the sprays will actuate simultaneously. Simultaneous actuation could produce negative pressure transients in the containment and aggravate temperature stratification in the suppression pool.

14. RHR Backflow Through Containment Spray

A failure in the check valve in the LPCI line to the reactor vessel could result in direct leakage from the pressure vessel to the containment atmosphere. This leakage might occur as the LPCI motor operated isolation valve is closing and the motor operated isolation valve in the containment spray line is opening. This could produce unanticipated increases in the containment spray.

15. Secondary Containment Vacuum Breaker Plenum Response

The STRIDE plants had vacuum breakers between the containment and the secondary containment. With sufficiently high flows through the vacuum breakers to containment, vacuum could be created in the secondary containment.

16. Effect of Suppression Pool Level on Temperature Measurement

Some of the suppression pool temperature sensors are located (by GE recommendation) 3" to 12" below the pool surface to provide early warning of high pool temperature. However, if the suppression pool is drawn down below the level of the temperature sensors, the operator could be misled by erroneous readings and required safety action could be delayed.

17. Emergency Procedure Guidelines

The EPGs contain a curve which specifies limitations on suppression pool level and reactor pressure vessel pressure. The curve presently does not adequately account for upper pool dump. At present, the operator would be required to initiate automatic depressurization when the only action required is the opening of one additional SRV.

18. Effects of Insulation Debris

18.1 Failures of reflective insulation in the drywell may lead to blockage of the gratings above the weir annulus. This may increase the pressure required in the drywell to clear the first row of drywell vents and perturb the existing load definitions.

18.2 Insulation debris may be transported through the vents in the drywell wall into the suppression pool. This debris could then cause blockage of the suction strainers.

19. Submergence Effects on Chugging Loads

19.1 The chugging loads were originally defined on the basis of 7.5 feet of submergence over the drywell to suppression pool vents. Following an upper pool dump, the submergence will actually be 12 feet which may effect chugging loads.

19.2 The effect of local encroachments on chugging loads needs to be addressed. (pp. 251-252 of 5/27/82 transcript)

20. Loads on Structures Piping and Equipment in the Drywell During Reflood

During the latter stages of a LOCA, ECCS overflow from the primary system, can cause drywell depressurization and vent backflow. The GESSAR defines vent backflow vertical impingement and drag loads, to be applied to drywell structures, piping, and equipment, but no horizontal loading is specified.

21. Containment Makeup Air For Backup Purge

Regulatory Guide 1.7 requires a backup purge H_2 removal capability. This backup purge for Mark III is via the drywell purge line which discharges to the shield annulus which in turn is exhausted through the standby gas treatment system (SGTS). The containment air is blown into the drywell via the drywell purge compressor to provide a positive purge. The compressors draw from the containment, however, without hydrogen lean air makeup to the containment, no reduction in containment hydrogen concentration occurs. It is necessary to assure that the shield annulus volume contains a hydrogen lean mixture of air to be admitted to the containment via containment vacuum breakers.

22. Miscellaneous Emergency Procedure Guideline Concerns

The EPGs currently in existence have been prepared with the intent of coping with degraded core accidents. They may contain requirements conflicting with design basis accident conditions. Someone needs to carefully review the EPG's to assure that they do not conflict with the expected course of the design basis accident.

THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

P.O. BOX 5000 ■ CLEVELAND, OHIO 44101 ■ TELEPHONE (216) 622-9800 ■ ILLUMINATING BLDG. ■ 55 PUBLIC SQUARE

Serving The Best Location in the Nation

Dalwyn R. Davidson
VICE PRESIDENT
SYSTEM ENGINEERING AND CONSTRUCTION

July 21, 1982

Mr. Harold Denton, Director
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

Perry Nuclear Power Plant
Docket Nos. 50-440; 50-441
Extension of Construction Permit
Numbers CPPR-148 and CPPR-149

Dear Mr. Denton:

Enclosed herewith is an application for amendment of construction permit numbers CPPR-148 and CPPR-149 to extend construction completion dates.

We interpret this to be a Class II amendment per 10 CFR Part 170, and enclose a check for $1,200.00.

Very truly yours,

Dalwyn R. Davidson

Dalwyn R. Davidson
Vice President
System Engineering and Construction

DRD:mb

cc: Jay Silberg, Esq.
John Stefano
Max Gildner

B001
w/check $1,200
Add: John Stefano

UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

In the Matter of	)	
	)	
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY, et al.	)	Docket Nos. 50-440 50-441
	)	
(Perry Nuclear Power Plant, Units 1 and 2)	)	

APPLICATION FOR AMENDMENT OF CONSTRUCTION PERMITS NOS. CPPR-148 AND CPPR-149 TO EXTEND CONSTRUCTION COMPLETION DATES

The Cleveland Electric Illuminating Company, Duquesne Light Company, Ohio Edison Company, Pennsylvania Power Company, and The Toledo Edison Company (hereinafter "Permittees") are the co-holders of Construction Permits Nos. CPPR-148 and CPPR-149 authorizing construction of the Perry Nuclear Power Plant, Units 1 and 2.

Construction Permit No. CPPR-148 currently specifies December 31, 1982 as the latest date for completion of construction of Unit 1. Construction Permit No. CPPR-149 currently specifies June 30, 1984 as the latest date for completion of construction of Unit 2. Permittees' currently scheduled dates of commercial operation are May, 1984, for Unit 1 and May, 1988, for Unit 2. In order to provide for further time contingencies as explained below, and pursuant to 10 CFR §50.55(b), Permittees respectfully request that the Nuclear Regulatory Commission amend Construction Permit No. CPPR-148 to specify November 30, 1985 as the latest date for completion of construction of Unit 1 and Construction Permit No. CPPR-149 to specify November 30, 1991 as the latest date for completion of construction of Unit 2.

The extensions of time for the construction completion dates are needed because of the following:

1. Since construction of Perry began, projections of the growth rate in the demand for electricity have been significantly reduced as a result of the slowdown in industrial growth, increased

availability of natural gas, and conservation efforts by customers. This reduced growth rate has delayed the need for the capacity to be supplied by the Perry units.

2. Numerous changes and additional requirements for plant design and analysis have been incorporated, including those required by the Commission as a result of the Three Mile Island accident and during the course of the NRC's regulatory review.

   These substantial changes have dictated successive extensions of our project schedule to reflect the time required for completion of additional procurement and construction activities.

3. Increasing financing requirements caused by changes in plant design, increased plant construction costs and the sustained high rates of inflation during the past several years, have increased the difficulties in obtaining capital funds.

THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

By Dalwyn R. Davidson
Dalwyn R. Davidson
Vice President
System Engineering and Construction

and subscribed before me,
st day of July, 1982

Caroline M. Wilde
ublic

ission expires on:
l 17, 1985

CAROLINE M. WILDE
ry Public, State of Ohio
ission Expires April 17, 1985
corded in Lake County)

CERTIFICATE OF SERVICE

This is to certify that copies of the foregoing OHIO CITIZENS FOR RESPONSIBLE ENERGY MOTION FOR LEAVE TO FILE ITS CONTENTIONS 21 THROUGH 26 were served by deposit in the U.S. Mail, first class, postage prepaid, this 18th day of August, 1982 to those on the service list below.

Susan L. Hiatt

SERVICE LIST

Peter B. Bloch, Chairman
Atomic Safety and Licensing Board
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